Available online at www.sciencedirect.com
ScienceDirect
Energy Procedia 63 (2014) 1703 – 1726
Energy Procedia

GHGT-12

Flexibility of low-CO_2 gas power plants: Integration of the CO_2 capture unit with CCGT operation

Nicola Ceccarelli, Monica van Leeuwen, Tanja Wolf, Peter van Leeuwen, Rick van der Vaart, Wilfried Maas[a*], Alfredo Ramos[b]

[a]*Shell Global Solutions, Carel van Bylandtlaan 23, 2596 HP The Hague, The Netherlands*
[b]*Process Systems Enterprice, 26-28 Hammersmith Gr, London W6 7HA, United Kingdom*

Abstract

CCGT power is well-positioned for flexible operation due to its favorable dynamic character and is likely to play a significant role in the future intermittent power generation mix, specifically with an increasing penetration of intermittent renewable power capacity. However, concerns exist around the impact of adding Carbon Capture & Storage on the flexibility of low-CO_2 fossil fuel power plants. This paper presents the results of a study on the dynamics of a carbon capture plant in order to address the impact on flexibility. This will enable the development of the learning curve to improve flexibility of future commercial scale CCGT-CCS plants.

A dynamic model was set-up for a CCS retrofit on an existing typical commercial CCGT plant. Various load-following, shutdown and start-up scenarios were studied. It was concluded that flexibility of gas-fired power plants for mid-merit cycling or base-load operation does not have to be limited by the addition of post-combustion CO_2 capture. It was concluded that only start-up scenarios may lead to additional CO_2 losses, which can be limited by appropriate design. Various options to enhance start-up response have been identified and require further study and development to explore their value. The dynamic modelling capability built for this study provides an excellent tool to do this. It is noted that, starting from early FOAK CCGT-CCS power plants, a learning curve will be required to further develop flexible operation. Reference is made to the learning curve that delivered the current flexibility of CCGT power plants, where the steam cycle follows load variations on the gas turbine.

Peer-review under responsibility of the Organizing Committee of GHGT-12

Keywords: Flexible; flexibility; power; carbon dioxide; capture; sequestration; dynamic model; integration; CCS; learning curve

* Corresponding author. Tel.: +31-20-630-7326; fax: +31-20-630-2900.
E-mail address: Wilfried.maas@shell.com

Peer-review under responsibility of the Organizing Committee of GHGT-12
doi:10.1016/j.egypro.2014.11.179

1. Introduction

CCGT (Combined Cycle with Gas Turbines) power, through continuous development, is well-positioned for flexible operation due to its favorable dynamic character and is likely to play a significant role in the future intermittent power generation mix. With an increasing penetration of intermittent renewable power capacity, such as wind and photo-voltaic, mid-merit dispatchable CCGT's will become even more important for managing intermittency and for grid robustness [1]. CCGT favorable dynamic characteristics are:

- Good cycling capability with fast start-up;
- Fast ramp rates (minutes timescale to ramp from 30% to 100% load);
- Fast load response (seconds timescale to follow load variations by 5-15%);
- Good efficiency at part-load;
- Compared to coal, the impact of low load factors on Long Run Marginal Costs (LRMC) is lower for gas-fired power, due to its lower CAPEX/OPEX ratio (see Figure 1).

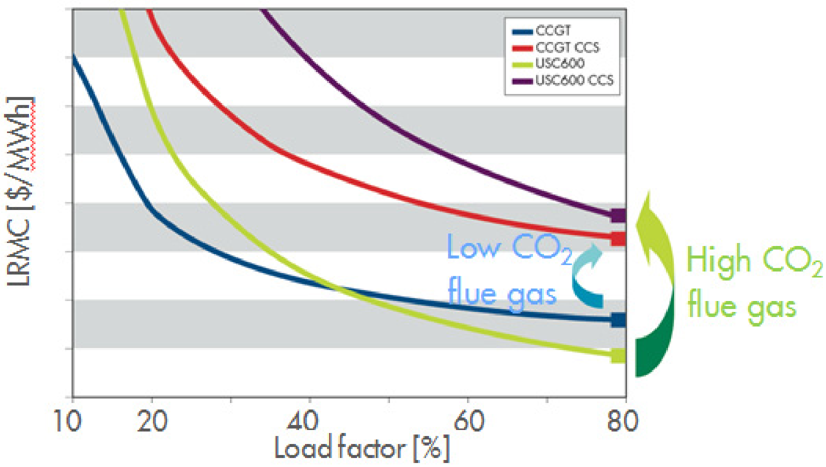


Fig. 1. Natural gas fired combined cycle power is better positioned than coal-fired at lower load-factors, especially for schemes including CCS (USC600 is ultrasupercritical pulverized coal fired powered combined cycle with a steam temperature of 600°C; LRMC at 0 \$/ton CO_2) [7].

Furthermore, recently, suppliers have been progressing CCGT technology to offer plants with further improved dynamic characteristics [2, 3]. Hence, flexible CCGT, more than coal, is likely to play a significant role in the future power generation mix, in conjunction with base-load power sources, like nuclear and base-load CCGT, and intermittent sources, particularly, wind [4].

CCS is being developed for both coal-fired and gas-fired power plants to deliver CO_2 reductions for fossil power. Amongst others, the International Energy Agency Greenhouse Gas (IEAGHG) have highlighted "electricity from gas-fired plants with CCS is likely to be cost competitive against coal plants with CCS", also in base load service [5]. However, concerns exist, also with the IEAGHG, around the impact of adding Carbon Capture & Storage on the flexibility of low-CO_2 fossil fuel power plants, either in base-load or cycling low-CO_2 power supply service [6]. Some studies have been published, specifically for coal CCS, but the number of studies on CCGT, for their mid-merit role, is limited.

This paper presents the results of a study on the dynamics of a carbon capture plant in order to address the impact on flexibility. This will enable the development of the learning curve to improve flexibility of future commercial scale CCGT-CCS plants. This study was conducted by Shell in co-operation with Process Systems Enterprise, who provided the dynamic modeling capability.

Nomenclature

CCGT	Combined Cycle with Gas Turbines
CCS	Carbon Capture & Storage
DCC	Direct Contact Cooler
FOAK	First Of A Kind
gSAFT	general Statistical Association Fluid Theory
GT	Gas Turbine
HPST	High Pressure Steam Turbine
HRSG	Heat Recovery and Steam Generation
LP	Low-Pressure
LPST	Low-Pressure Steam Turbine
LRMC	Long Run Marginal Costs
MEA	Monoethanolamine
MPST	Medium Pressure Steam Turbine
NOAK	Nth Of A Kind
OCGT	Open Cycle Gas Turbines
PID	Proportional-Integral-Derivative
mtpa	million ton per annum
(k)tph	(kilo)ton per hour
USC600	UltraSuperCritical with 600°C steam temperature
WHB	Waste Heat Boiler

2. The CCGT-CCS system

The present study specifically focuses on the dynamic behavior of a post combustion CO_2 capture plant in response to various operational scenarios of the CCGT power plant that delivers the flue gas. Figure 2 schematically shows the components that compose the low-CO_2 power system from gas turbine (GT) to the injection wells that may inject the CO_2 into an empty gas field or aquifer for sequestration or into an oil field for enhanced oil recovery purposes. The dynamic behavior of low-CO_2 power chain components, like the flue gas blower, direct contact cooler (quench), CO_2 conditioning (oxygen removal and dehydration) and compression, pipelines, wells and subsurface were not included in the scope of this study. The flexibility of these components will be determined by an appropriate specification of their dynamic behavior. Measures to enhance flexibility of these parts may include adjustable inlet guide vanes and a recycle on the CO_2 compression train, the use of variable speed drive electrical motors, the use of CO_2 pipeline packing and liquid CO_2 storage to accommodate CO_2 feed fluctuation on the wells and subsurface, in combination with integrated supply chain feed-forward control based on expected/predicted power demand. Another critical item may be the flue gas blower that needs to provide sufficient head to overcome the pressure drop over the direct contact cooler and absorber tower. Detailed studies on the integrated low-CO_2 power supply chain dynamics will be reported separately.

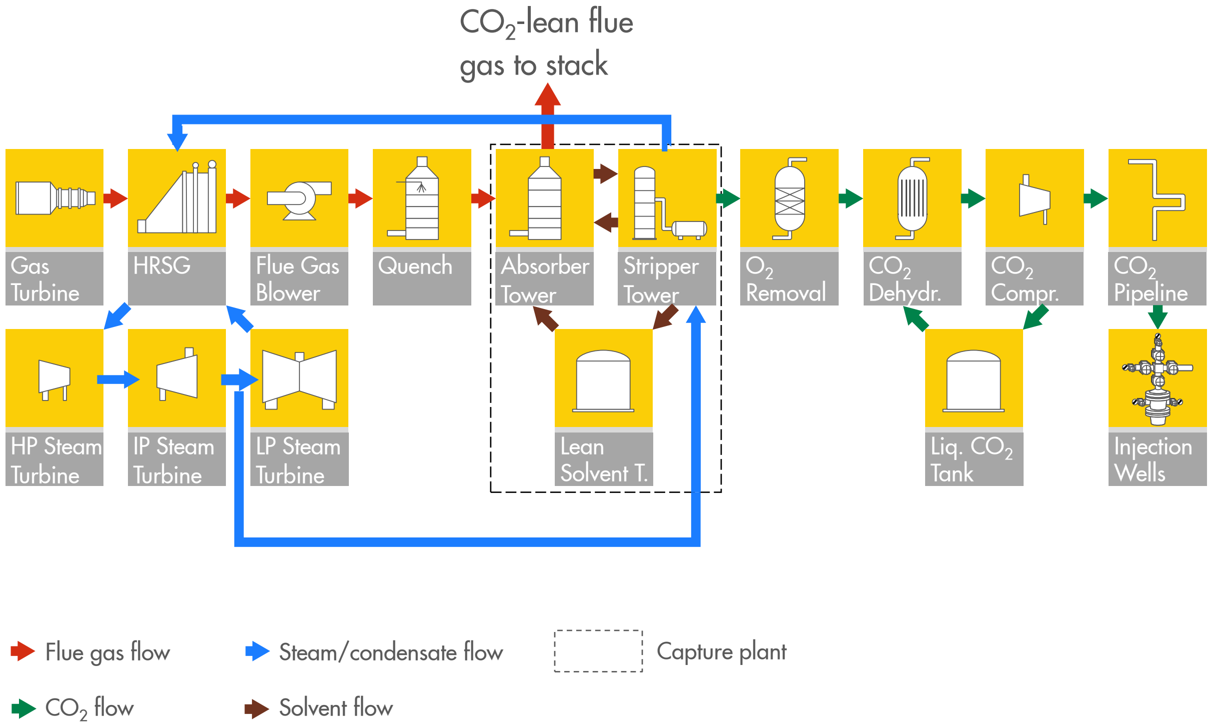


Fig. 2.The CCGT-CCS system

The stripper tower of the solvent system utilizes low-pressure (LP) steam as heat source for solvent regeneration in order to ensure a continuous flow of lean solvent into the absorber tower for effective CO_2 capture. Through integration of power plant and capture plant, LP steam is extracted downstream the intermediate-pressure (IP) steam turbine and routed to the reboilers on the stripper column.

2.1. The amine plant

The dynamic model was set-up largely in accordance with the capture plant Basis for Design for a full-scale natural gas-fired combined cycle with CCS project, with a CO_2 capture capacity of 1 mtpa (mln ton per annum). In order to capture 90% of the CO_2 in the approx. 2.4 ktph (kiloton per hour) flue gas from a single gas turbine with an output of 350 MWe (net, clean), the study assumed a 50% aqueous MEA solvent rate of approx. 3 ktph, to be deployed in a concrete absorber tower of approx. 20x15x50 meters (length x width x height) with a number of structured packing sections for absorption and water wash. To regenerate the solvent, a swaged stripper column with a diameter of approx. 8m and a height of approximately 25 m containing a stripping section and a rectifying section swaged on top of it, is used. The reboilers on the stripper consume approximately 180 tph of LP steam (approx. 140°C) at full capacity. Figure 4 shows the process flow sheet of the amine plant, where the absorber for modelling purposes has been split into three sections: bottom section with sump and first contacting stage that receives intercooled solvent, middle section that receives lean amine from the lean amine tank and a top section that provides a water wash to minimize amine emissions with the treated flue gas.

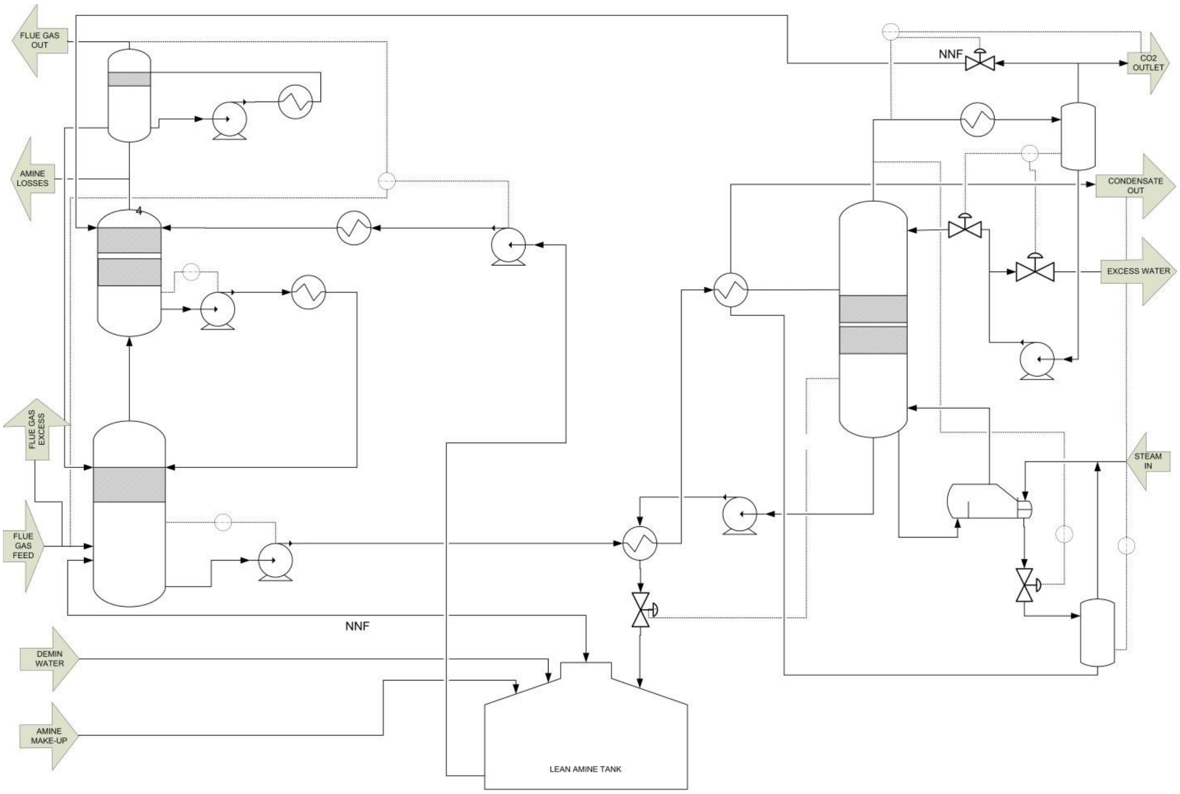


Fig. 3. The amine plant process flow sheet

3. Setting-up the dynamic modelling capability

3.1. General

This study presents the first commercial application of Process Systems Enterprise's gCCS, an integrated modelling and simulation environment for whole-chain CCS systems, supported by the gPROMS unified modelling platform. The gCCS software package [8-10] was developed to address challenges like:

- Steady-state and dynamic modelling of whole CCS networks within a single environment;
- Accurately predicting solvent-CO_2 thermodynamic behavior[*];
- Accurately predicting phase behavior of near-pure CO_2 mixtures with characteristic impurities of pre- and post-combustion capture processes;
- Fast and robust numerical solution of complex dynamic behavior in full transient dynamics like power plant load variations, start-up and shutdown;

[*] Components included were MEA (for this dynamic simulations MEA was used as a proxy for the commercial Shell Cansolv solvent), water, CO_2 and N_2, the latter lumping all other gaseous components

- Merging the rate based absorber and stripper models with the dynamic simulation flow-scheme environment;
- Providing optimization functionality for the full dynamic system.

Physical properties in gCCS are provided by gSAFT, a PSE proprietary package based on Statistical Association Fluid Theory that incorporates a number of variations of this equation of state that were originally developed at Imperial College [11-14]. To capture the essential dynamics but maintain a fit-for-purpose model in the gCCS/gPROMS environment, the following main equipment types were included in the model:

- Solvent circulation pumps;
- Cross exchangers, coolers and reboilers, including steam control to maintain reboiler temperature (solvent leanness);
- Absorber and stripper columns and lean amine tank;
- PID control loops for:
  - CO_2 capture ratio;
  - Stripper temperature and pressure;
  - Columns liquid level.

The model boundaries were set to:

- Flue gas inlet to absorber column (flow and temperature);
- Absorber gas outlet (pressure);
- Steam inlet to reboiler (flow, temperature);
- CO_2 compressor inlet (flow);

In Sections 3.2-3.4, the absorber, stripper and lean amine tank model are described in more detail.

3.2. Absorber section

The flue gas feed flow was modelled as a fixed composition flow stream into the bottom section of the absorber. The column sumps were modelled as tanks. Separate packing sections in the absorber column were modelled as discrete rate based mass transfer entities with a discretization into 20 elements in the axial direction. The water wash section in the top of the absorber was modelled as a flash calculation. Distributors, redistributors and other internals were not included in the model. Liquid hold-ups in the packing sections were calculated using the Billet and Schultes model [15]. For bed pressure drop calculation, the dry bed friction factor was used [16].

The water wash pump delivers cooled wash water to the absorber top section. Lean solvent is cooled and pumped into the top of the middle section of the absorber where it flows down, counter-currently with the upward flue gas flow. The resulting enriched solvent is then pumped through an intercooler to the top of the absorber bottom section. The rich solvent from the sump is then pumped via the lean/rich heat exchanger to the stripper column. The cooling water flow to the coolers was assumed constant.

The capture ratio was controlled by a PID controller on the main solvent circulation pump that pumps lean solvent from the lean solvent tank into the middle section of the absorber. The CO_2 capture ratio was defined such that CO_2 emissions from the top of the absorber (which are routed to stack), as well as from venting excess flue gas upstream the absorber, are accounted for.

3.3. Stripper section

The stripper was modeled as two separate units: stripper section and top section. The reflux from the condenser flows to the top section, which is modeled as a flash, where it is mixed with the pre-heated rich solvent that comes from the lean/rich exchanger via the rich/steam condensate exchanger. The mixture flows down the stripper section in counter current with steam traffic upwards through the stripper section into the sump and reboiler. The stripper section was modeled as discrete rate based mass transfer entities with a discretization into 20 elements in the axial direction. The reboiler boils part of the stream, thus generating the lean solvent that is pumped to the lean/rich heat exchanger. Table 1 specifies key reboiler data.

The CO_2-rich steam from the stripper top sections flows through a simple pipe section to the condenser where steam is condensed , which leaves a wet CO_2 vapor product. The pressure control scheme on the condenser decides whether the CO_2 is routed to CO_2 conditioning (dehydration and oxygen removal) and compressor stages or to the absorber top to be vented. The condenser temperature is controlled by adjusting the cooling water flow. The liquid level was controlled by a split range controller directing the liquid back to the stripper top (normal operation) or to the excess water sink.

The sump level controller controls the flow of solvent from the stripper sump into the reboiler, where the temperature is controlled by manipulating the LP steam flow to the reboiler. The resulting steam condensate is sent to a condensate drum of which the level is controlled by manipulating the condensate flow from the drum to the condensate/rich amine heat exchanger for pre-heating the rich solvent before it flows into the stripper top section. The reboiler liquid level is controlled by manipulating the lean solvent flow towards the lean/rich crosses exchanger. The reboiler pressure was controlled by limiting the vapor flow towards the stripper section.

Table 1. Reboiler data

Reboiler specific duty	MJ/ton	3.6
Steam consumption	Kg/s	50
Reboiler temperature	°C	121
Reboiler pressure	bar	2

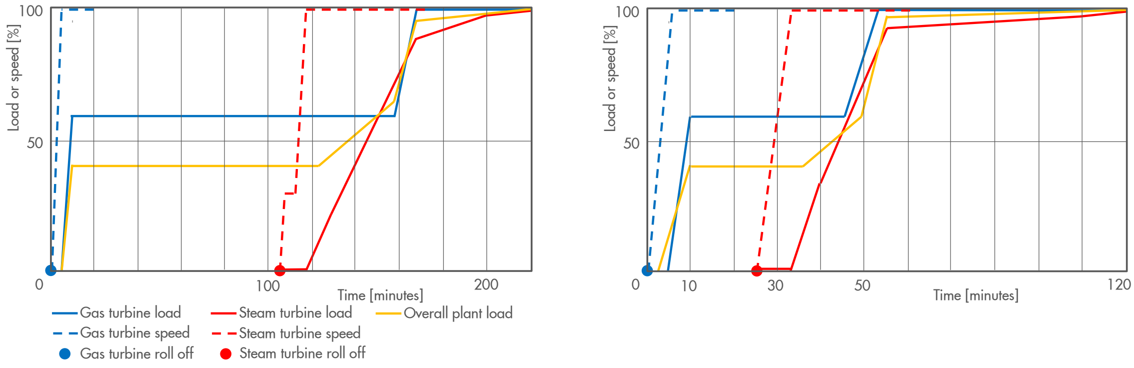
3.4. Lean amine tank and amine make-up

The lean solvent that is cooled in the lean/rich cross exchanger, flows into the lean amine tank. MEA and water losses were compensated for by separate MEA and water make-up into the lean amine tank. Water make-up was controlled to maintain the liquid level in the lean amine tank. The make-up MEA flow was controlled to maintain the MEA/water ratio.

4. Power plant dynamic behavior

4.1. Start-up and shutdown sequences

A CCGT power plant starts up in a particular sequence of which the duration of the various steps depends on the initial state of the plant (hot, warm or cold). Understanding the start-up and shutdown sequences is key in developing integration options of power plant and capture plant. Figure 4 schematically shows indicative examples of a cold and a hot start-up sequence in terms of gas/steam turbine speed and load. Initially, the GT is ignited and accelerated up to full speed in a few minutes, after which the GT is synchronized with the grid. Subsequently, the GT is loaded to a nominal power level of 60%. Meanwhile, the HRSG system is heating up and starts to produce low-quality steam which bypasses the steam turbine and is dumped in the condenser (or in the CO_2 capture unit, as will be suggested in Section 6). At the moment the available steam is of sufficient quality, the steam turbines are rolled-off and accelerated by slowly closing the steam bypass valve. Depending on power demand, the GT and ST are further loaded. Note that these plots are only indicative. Durations and ramp rates depend on the specific system performance and power demand.



a b

Fig. 4. Start-up sequence examples of CCGT power plant for cold start (a) and hot start (b) [17]

At shutdown, first the ST's are unloaded and disconnected from the grid. Excess steam is slowly redirected to the condenser. Subsequently, the GT's are unloaded and stopped. See Figure 5.

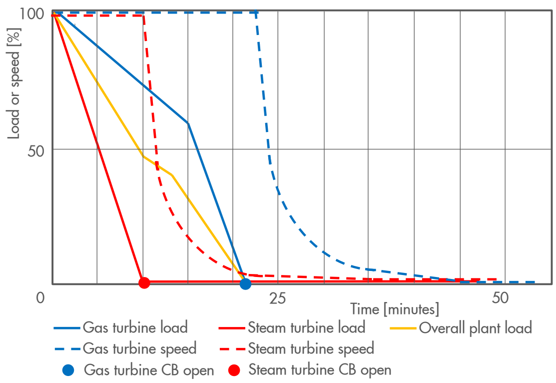


Fig. 5. Shutdown sequence example of CCGT power plant [17]

4.2. Ramp rates

To understand what dynamic power plant behavior a capture plant will need to respond to, dynamic data sets from commercial operations were analyzed. For setting-up dynamic modelling, it is required to understand the rate at which load variations occur. The particular ramp rates in power output of a CCGT power plant, largely, determine the changes in flue gas mass flow and, hence, CO_2 mass flow the CCS plant will be exposed to. Analysis of commercial (base-load) plant data provided insight in the ramp rates that occur. Figure 6 provides an overview of observed ramps as a function of the delta megawatt range covered. Figure 7 provides some functional definition of the ramps observed:

- Start-up ramps that are steep in the very first megawatts: around 10 MWe/min;
- Ramps to minimum turndown level: around 4 MWe/min;
- Load following responses in between minimum turndown and full capacity: up to 6 MWe/min;
- Ramps to full capacity: around 8 MWe/min.

Overall, except for a few occasions shortly after start-up, ramp rates do not exceed 10 MWe/min but more typically do not exceed 8 MWe/min. In terms of flue gas mass flow towards the capture plant, the latter equals 0.9

ton/min^2 (based on a flue gas mass flow rate at full capacity of 40 ton/min for 350 MWe clean power production). This is the ramp rate taken forward in the present study, although it is appreciated that this largely depends on the CCGT-CCS configuration (e.g., 2 GT's into a single CCS unit) and the specific system (e.g., a fast response system [2,3]) at hand. The learning curve will need to bring the future CCS system dynamic response to the higher ramping capabilities of the developing fast response CCGT systems.

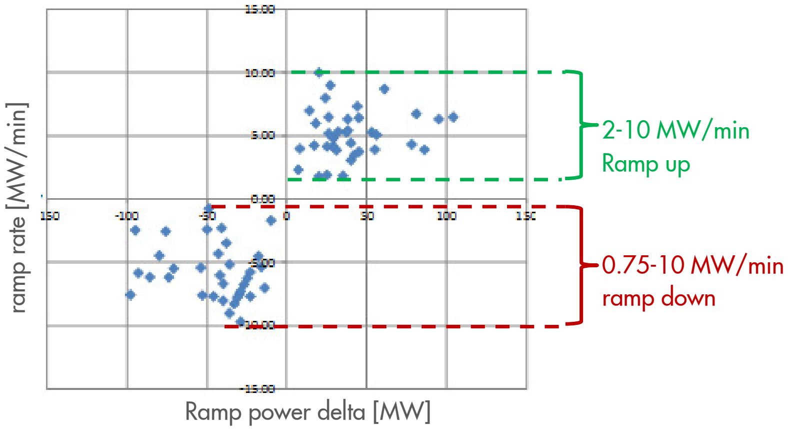


Fig. 6. Typical ramp rates for a 400 MWe base-load CCGT unit [17]

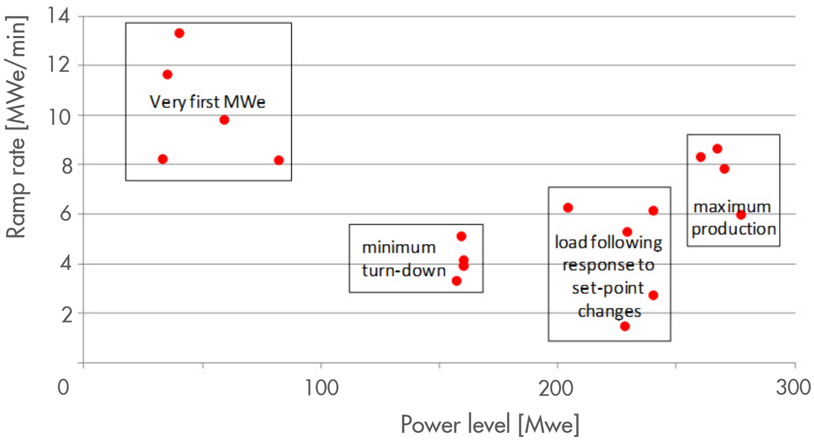


Fig. 7. Ramp types observed in a commercial 400 MWe base-load CCGT unit [17]

4.3. Start-up frequency

Figure 8 shows indicative frequencies of restarts after varying durations of shutdowns. This results in a frequency distribution for cold, warm and hot starts, close to the base load plant frequencies as given in Table 2. For comparison, also data for intermediate and cycling power plants are shown.

These data will allow an estimation of the amount of CO_2 not captured and steam inefficiencies as a consequence of potential delays in CCS capacity availability upon start-up, load leveling or shutdown of the power plant.

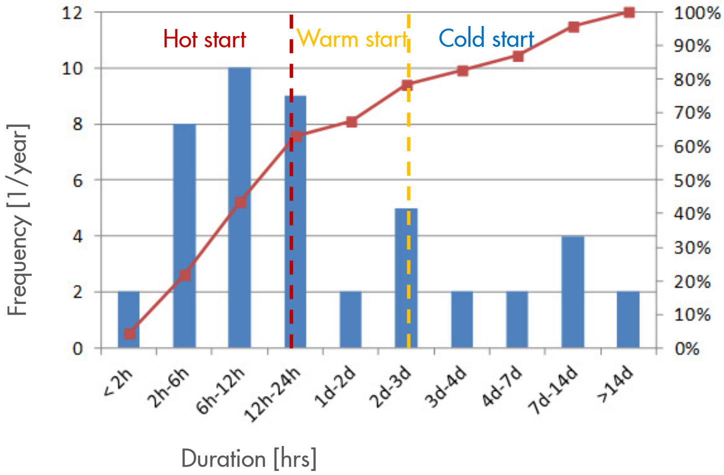


Fig. 8. Restart frequency as a function of shutdown duration for a commercial 400 MWe base-load CCGT plant [17]. Down-time prior to hot start: <16hrs, warm start: 16-64 hrs, cold start:>64 hrs

Table 2. Number of cold, warm and hot starts per annum per type of power plant service [18]

	Down-time prior to start	Typical base load plant	Typical intermediate plant	Typical cycling plant
Cold starts	>64 hrs	9	17	18
Warm starts	16-64 hrs	7	63	79
Hot starts	<16 hrs	13	77	360

5. Dynamic modelling results

With the dynamic model set-up, various runs were executed to investigate the response of the capture plant for the following transients:

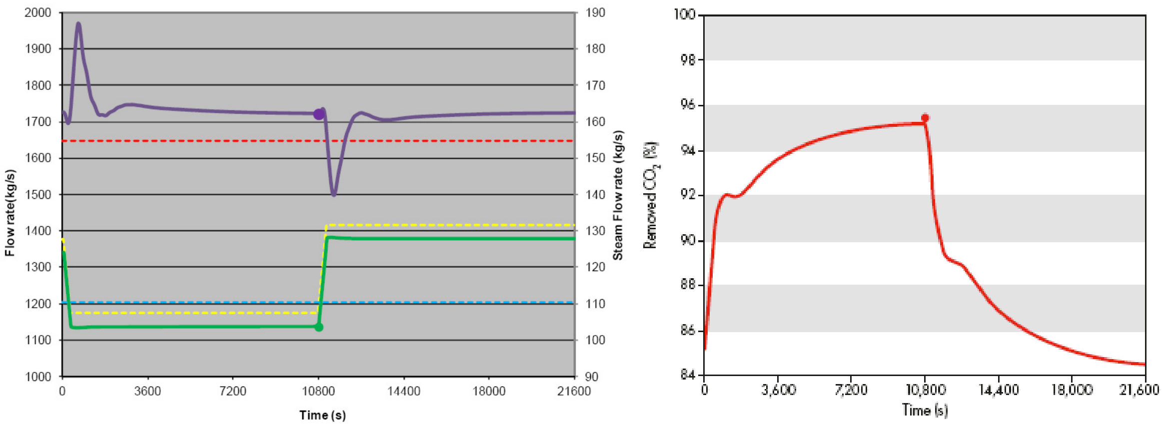
1. Load following:
   a. uncontrolled;
   b. with control of solvent rate as a function of flue gas mass flow and steam mass flow as a function of solvent rate;
2. CCS shutdown: ramp down in flue gas and steam in 1 minute to nil (emergency shutdown scenario):
   a. with solvent recirculation stopped;
   b. with solvent circulation reduced to 30% of full capacity;
3. Restart with LP steam once available from the steam turbines:
   a. Hot restart (within 16 hrs after shutdown), with an initial solvent loading of ~0.4 mol/mol, a stripper sump temp of 72°C and 30% solvent circulation rate;
   b. Cold restart (after more than 64 hrs after shutdown), with initially saturated solvent (~0.5 mol/mol), ambient stripper sump temperature (25°C) and no solvent circulation;
4. Cold restart with LP steam that is made available early by a presumed auxiliary boiler;

5.1. Load following

This case represents the response of a fully operational ”hot” CO_2 capture unit connected to a fully operational (hot) CCGT power unit, upon changes in power output demands. It is used to assess the inherent dynamics of the capture plant and the ability to control the capture efficiency of the capture unit during this load-following operation. These simulations were conducted with a previous version the model and process description and an 85% capture ratio target setting. Hence, the results show absolute flow rates that differ from the startup and shutdown cases that will be reported in Sections 5.2 and 5.3.

Uncontrolled load following

In this simulation, the flue gas flow rate was changed from 100% to 70% (t=0) and vice versa (t=10800s) at a rate of 5%/min. Lean amine and steam flow were kept constant. Figure 9a shows that the rich amine flow from the absorber initially increases due to a reduction in liquid holdup in the absorber. The initial fast increase in CO_2 removal (Figure 9b) is based on the higher relative liquid/gas (L/G) ratio to the absorbers where there is a substantially higher relative amount of amine to remove CO_2, thus, increasing the CO_2 removal efficiency. The further slow increase of the CO_2 removal is attributed to reduction of the CO_2 loading of the lean amine which is governed by the ratio of the lean solvent tank volume and amine circulation rate.

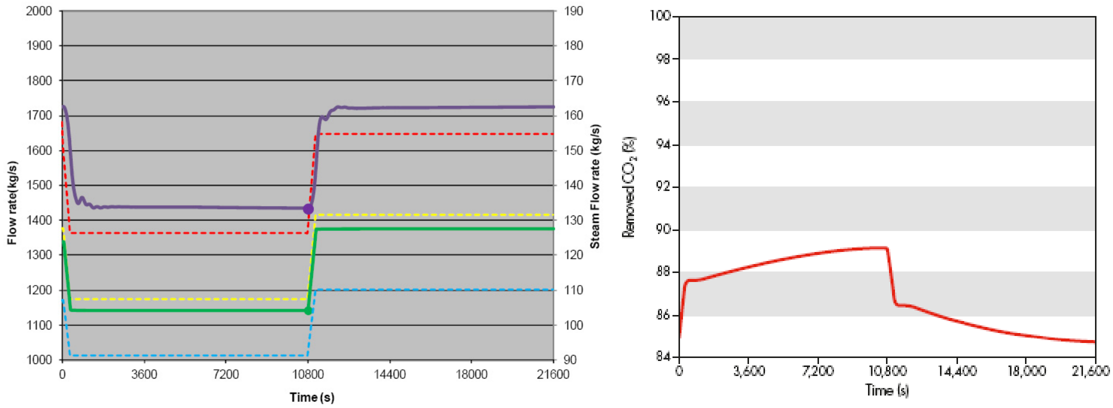


a b

Fig. 9. Uncontrolled load following model results upon adjustment of feed gas conditions (for two absorbers); a. Gas to absorber (yellow), gas from absorber (green) lean amine (red), rich amine (purple) and steam (blue, right hand axis) flows to/from the absorber/stripper, b. CO_2 capture ratio

Controlled load following

In this simulation, the flue gas flow rate was changed from 100% to 70% (t=0) and vice versa (t=10800s) at a change rate of 5%/min, now, with control of lean amine/ flue gas and amine/steam flow ratios. Figure 10a shows that the rich amine flow follows the lean amine feed flow, in this case.



a b

Fig. 10. Controlled (solvent rate and steam flow) load following model results upon adjustment of feed gas conditions (for two absorbers); a. Gas to 2 absorbers (yellow), gas from absorber (green) lean amine (red), rich amine (purple) and steam (blue, right hand axis) flows to/from the absorber/stripper, b. CO_2 capture ratio

The simulation results indicate that, under typical gas feed changes, the capture plant can be maintained close to its operating point in terms of fraction CO_2 removed (Figure 10b). In particular, by using the amine circulation rate and the steam rate to the regenerator reboiler as handles to respond to variations in feed gas rate, the lean and rich amine loading can be kept constant. This leads to a constant fraction CO_2 removed on the same time scale as the gas feed rate variations. The time scale on which the operating point can be changed is largely determined by the ratio of the amine buffer volume and amine recirculation rate and is, therefore, typically longer. With feed forward (from CCGT load control) and advanced controls control, improvements are possible. Note that CO_2/steam flow ratio control also will diminish the steam loss at lower loads and contribute to the overall process efficiency. Comparable performance (not reported) was found for larger load change (100-40%).

5.2. Shutdown case results

The shutdown case represents an extreme case in terms of ramping down the flue gas supply to the absorber. As indicated in Figure 11a, the flue gas mass flow linearly drops off to nil in 1 minute. This is a faster drop-off than will occur in any load following or turndown response during normal operation. Upon loss of flue gas, in the same pace, the steam supply to the reboilers (Figure 11b) and the solvent circulation rate (Figure 11c) are turned down, the latter to full stop (black curve) or to 30% turndown (red curve).

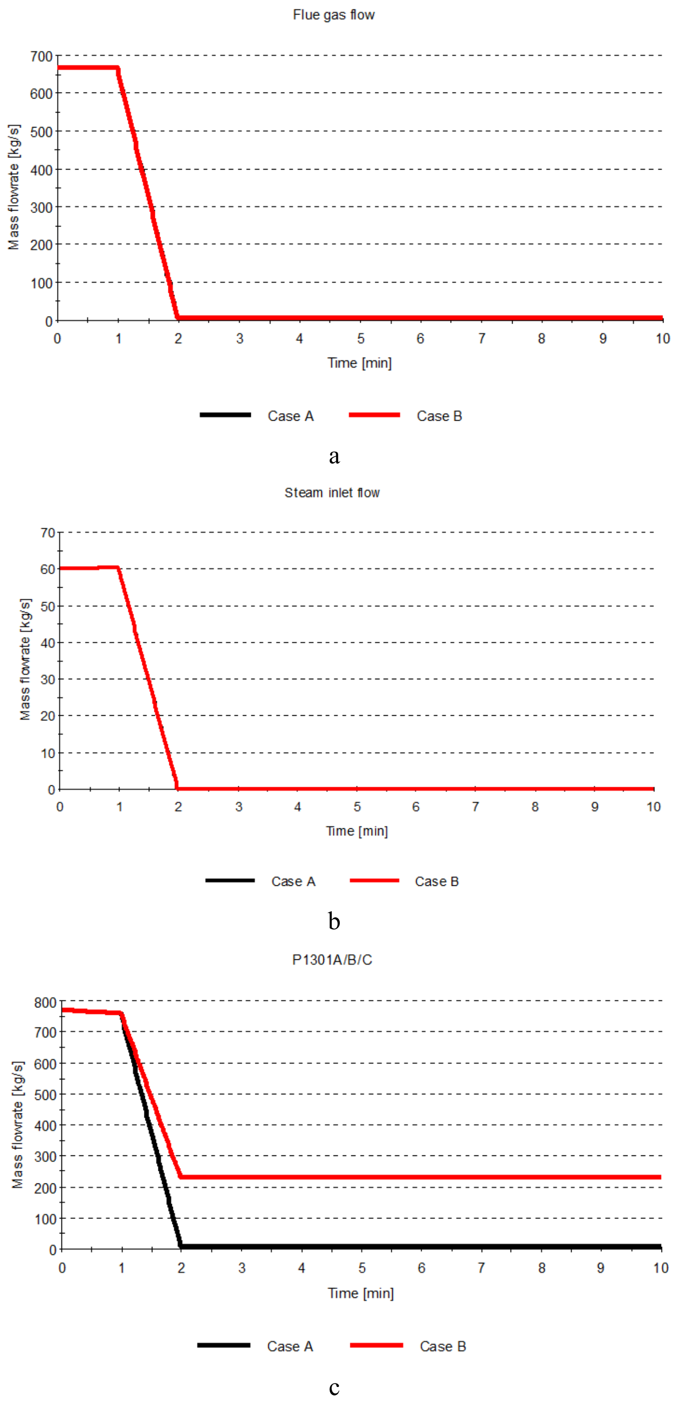
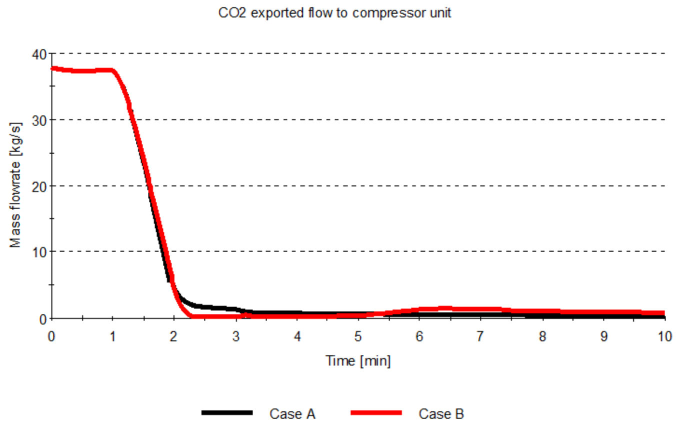
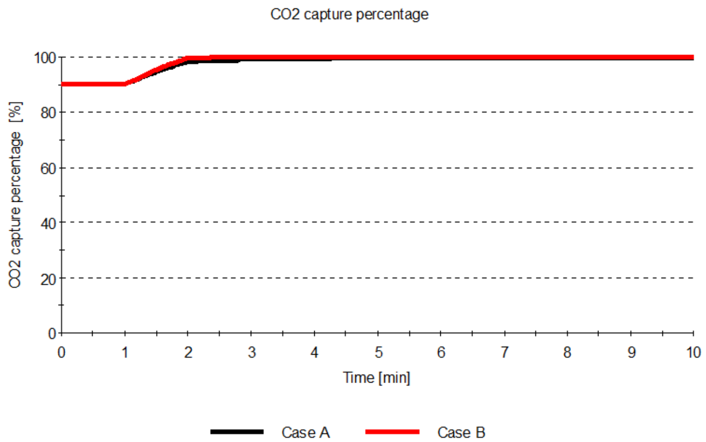


Fig. 11. Capture plant shutdown actions (black: full shutdown of solvent circulation; red: turndown to 30% of solvent rate). a. Flue gas mass flow; b. steam to reboiler mass flow; c. lean solvent flow into absorber.

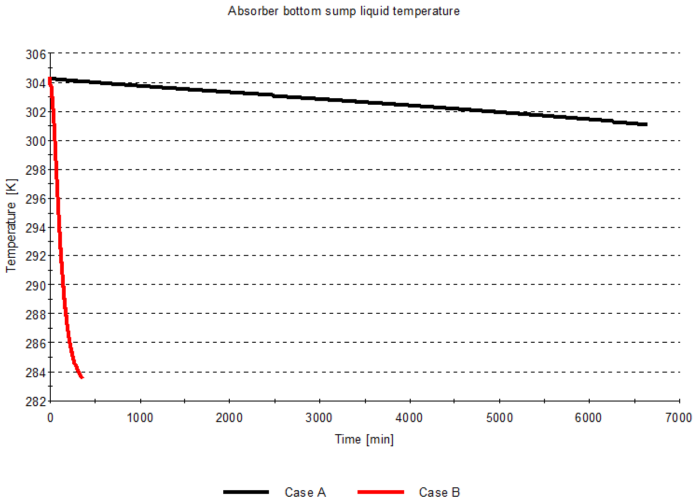
Figure 12 shows the capture system's responses to the above actions. Figure 12a shows that the CO_2 mass flow produced from the stripper column drops off in, virtually, the same pace as the steam supply to the reboilers, as should be expected, since the driving force for desorption of CO_2 from the rich solvent disappears. At the same time, the capture ratio of CO_2 from the flue gas in the absorber increases from the nominal target ratio of 90% to almost 100%. This is an important observation since this indicates that upon (emergency) shutdown or upon slower load reductions, no additional CO_2 will be emitted due to inertia in the capture system. Apparently, although solvent regeneration stops, the lean solvent inventory in the absorber, piping and lean solvent tank, are sufficient to maintain effective CO_2 absorption for the reducing flue gas mass flow.



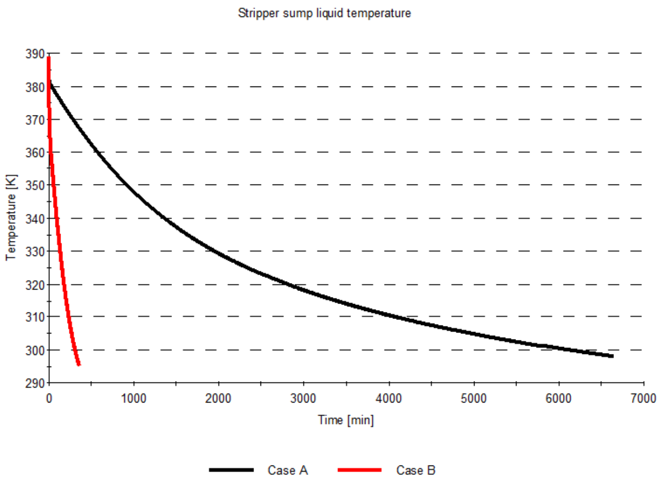
A



a



c



d

Fig. 12. Capture plant responses upon full power plant shutdown (black: full shutdown of solvent circulation; red: turndown to 30% of solvent rate). a. CO_2 mass flow from stripper to CO_2 conditioning; b. CO_2 capture ratio; c. absorber sump solvent temperature; d. stripper sump solvent temperature

Only very slight differences in the red (solvent turned down to 30%) and black (solvent circulation stopped) curves are visible in Figure 12a and b: CO_2 production from the stripper drops off more deeply, initially, when the solvent rate is turned down to 30%, and the CO_2 absorption increases more rapidly for the same case. Both effects can be explained from the temperature effects that occur in the absorber (Figure 12c) and the stripper (Figure 12d). When solvent circulation is maintained, more heat is dissipated in the lean/rich heat exchanger as well as the solvent intercooler and stripper condenser. Hence the solvent inventory in the whole capture system cools down more rapidly (~10 hrs to ambient) when circulation is maintained compared to when solvent circulation is stopped (~5 days to ambient). This has two effects:

- In the absorber, the lower temperature enhances absorption in the absorber (more favorable Henry coefficient while temperature still sufficiently high for favorable kinetics);
- In the stripper, the lower temperature reduces desorption in the stripper.

Besides the internal dissipation of heat, maintaining 30% solvent circulation rate also has an impact on solvent loading distribution in the system. Figure 13 demonstrates that, over time, the solvent stabilizes at a relatively high CO_2 loading. This will have an impact on capture readiness once flue gas flow ramps up and lean solvent needs to be available in the absorber to quickly respond to the increasing CO_2 supply. In that respect, a full shutdown on solvent circulation will be a more favorable shutdown strategy and give lower CO_2 emissions during ramp-up.

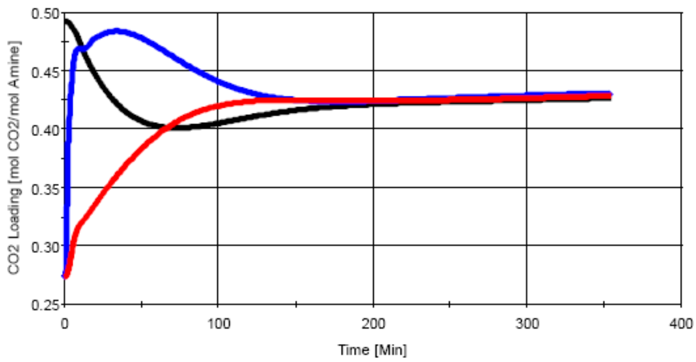


Fig. 13. Solvent loading responses upon full power plant shutdown with a remaining 30% solvent circulation rate (Case 1b; black: absorber sump; red: lean amine tank; blue: stripper sump).

In summary, the capture plant easily follows fast shutdown, without additional CO_2 emissions to the atmosphere. Full shutdown of the solvent circulation keeps more heat and more lean solvent in the system and is expected to provide the better capture response upon ramping-up flue gas supply.

5.3. Results for restart on LP steam from IP steam turbine outlet

This section provides the response of the capture system upon flue gas ramp-up from full shutdown to maximum capacity in 45 minutes (red curve in Figure 14), or a flue gas ramp rate of 0.9 ton/min^2, which was concluded to be the typical maximum value in Section 4.2. For this dynamic run, it was assumed that LP steam becomes available from the HRSG unit 30 minutes after the GT reached its maximum output. This point, 75 minutes after GT start-up, triggers the ramp-up of solvent circulation to maximum initial rate (Figure 15a) and, with a small delay of 5-10 minutes to allow for stable operation, triggers admission of LP steam to the reboiler (Figure 15b). Then, only after sustained steam supply to the reboiler, flue gas was admitted to the absorber (90 minutes after start-up with a linear ramp over 2 minutes, blue and black curves in Figure 14). Initially, the steam rate into the reboilers remains at maximum value to heat-up the solvent inventory to setpoint. Then, the steam rate drops off to a nominal rate to maintain a stable solvent temperature. Clearly, the hot case requires less time for heat-up than the cold case.

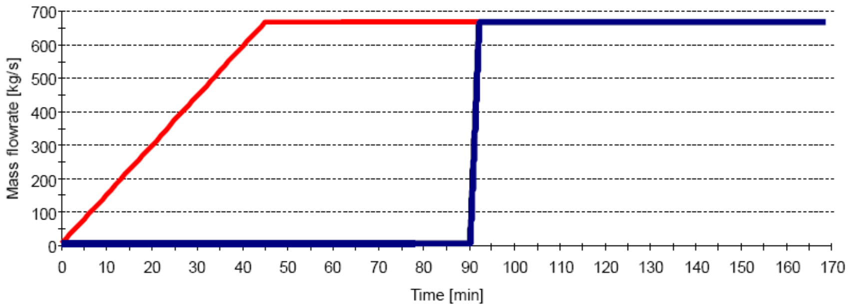


Fig. 14. Flue gas mass flow rate produced from gas turbine (red) and the actual admission of flue gas to the absorber tower (blue/black, equal for hot and cold restart).

Figure 15c demonstrates that CO_2 is produced from the stripper only minutes after LP steam is admitted to the reboiler, even before flue gas is admitted to the absorber tower. This is the direct consequence of the relatively high solvent loading at start-up. Clearly, the cold case produces more CO_2 since the initial solvent loading was higher (~0.5 mol/mol) than the hot case (~0.4 mol/mol), hence, more CO_2 is to be released on the way to the steady-state solvent loading distribution, which is equal for both cases (Figure 16).

Figure 15d illustrates that the hot restart case achieves a CO_2 capture ratio close to the setpoint much faster (10 vs. 20 minutes) than the cold restart case. Detailed analysis led to the conclusion that this is the consequence of the cold case waiting for lean solvent to arrive in the absorber, while the hot case does have “spare” solvent loading available at start. More interestingly, the rate at which setpoint CO_2 capture ratio is achieved is much faster than the time required achieving steady-state operation with all temperatures and solvent loading profiles established, typically 60 minutes after steam is admitted to the reboiler, as shown in Figures 15 and 16.

Note that the observed oscillations in Figure 15 and 16 are dynamic effects that are not of particular interest and the consequence of non-optimized tuning of the controllers as well as non-homogeneous distribution of solvent loading in the system after start-up.

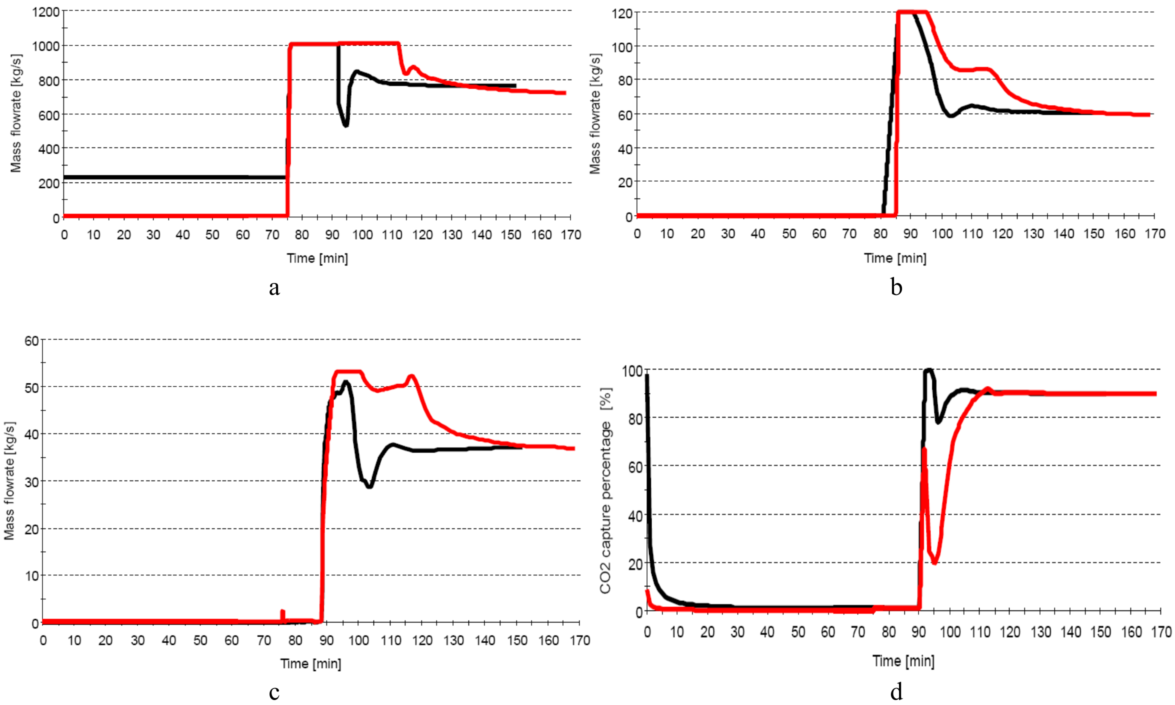


Fig. 15. Responses upon restart of solvent flow into absorber (a), steam inlet flow to reboiler (note that the different ramps applied for the hot and cold case are unintentional and do not affect the overall results) (b), CO_2 mas flow rate from stripper (c) and capture ratio (d); black: hot restart; red: cold restart

The delayed capture plant start-up results in CO_2 not being captured. Figure 17 presents the cumulative CO_2 loss to the atmosphere after rolling-off the gas turbine. Up to the point of achieving 90% capture ratio setpoint (which corresponds to a continuing CO_2 loss to the atmosphere of 4 kg/s), around 170 and 185 tons of CO_2 were lost for the hot and the cold case, respectively. It is interesting to note that the CO_2 loss after the actual admission of flue gas into the absorber, 90 minutes after rolling off the gas turbine, is negligible for the hot start-up case and amounts to around 20 tons of CO_2 for the cold case. Again, this is the consequence of the semi-lean solvent available in the hot start-up case.

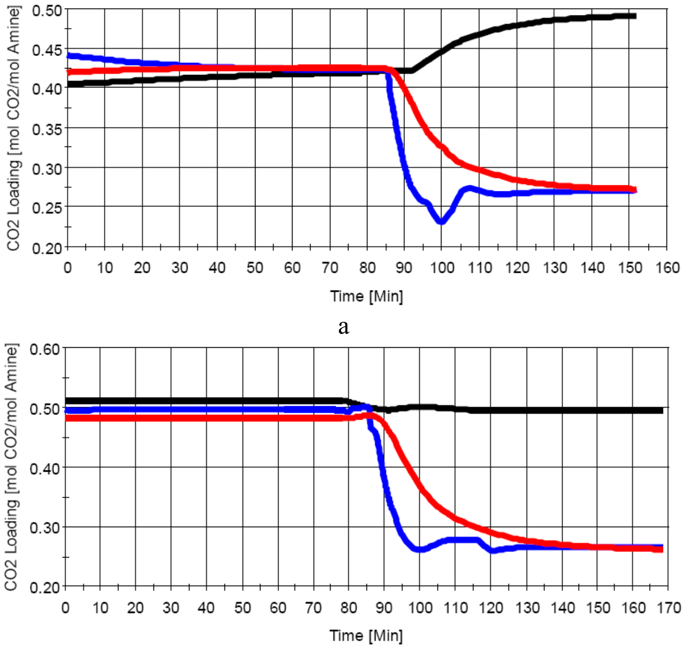


Fig. 16. Solvent loading responses upon hot restart (a) and cold restart (b); black: absorber sump; red: lean amine tank; blue: stripper sump

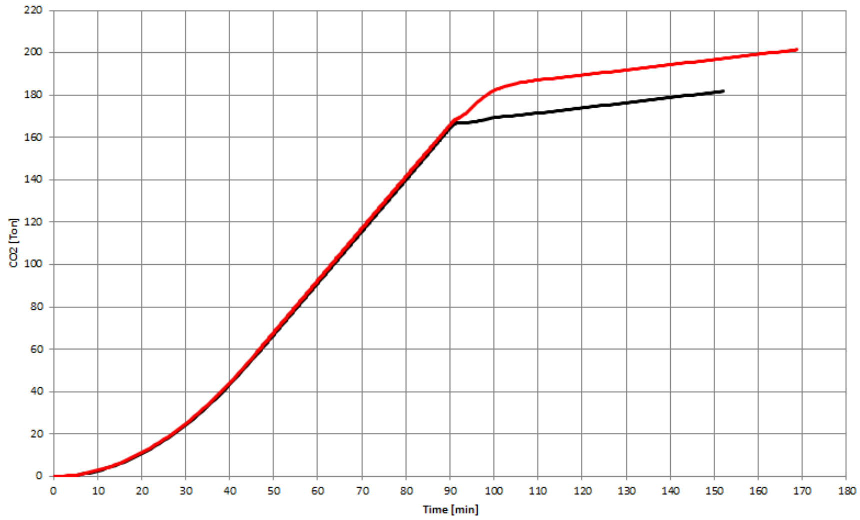


Fig. 17. Cumulative CO_2 loss to the atmosphere upon hot restart (black) and cold restart (red). In both cases, flue gas was admitted to the absorber at 90 minutes.

In summary, the above dynamics demonstrate that fast capture responses are achievable. The capture efficiency response to flue gas volume variation outpaces the capture system as a whole establishing a new steady-state. This was demonstrated for the extreme dynamic cases of restart from stop to full capacity at a very high ramp rate that exceeds the ramps observed in load-following mode during normal operation. Hence, this confirms load-following not to be leading to significant losses of CO_2 to the the atmosphere. The losses of CO_2 to the atmosphere presented in this section were merely a function of:

- the assumed intervals between start-up of the gas turbine and the admission of flue gas to the absorber tower. Hence, shortening of this time interval will almost linearly decrease CO_2 loss to the atmosphere. This will be demonstrated in Section 5.4;
- the availability of a non-saturated warm solvent feed into the absorber tower. Hence, it should be prevented that solvent saturation increases and heat is dissipated in the system, which pleas for stopping the solvent circulation upon shutdown;

5.4. Results for restart on external steam that is available earlier than LP steam from the steam turbines

This section demonstrates that making steam available to the reboiler 30 minutes earlier, e.g., by the use of an auxiliary boiler (as is the default for fast-ramping systems), and the corresponding early admission of flue gas to the absorber tower strongly decreases the CO_2 lost to the atmosphere. The cold start-up case was used since represents the preferred case of stopped solvent circulation. In this case, steam was made available to the reboiler as soon as the gas turbine reached its full flue gas production. Allowing for 15 minutes for stabilization of the system, flue gas was admitted to the absorber tower at 60 minutes, i.e., 30 minutes earlier than the cases reported Section 5.2. From Figure 18, it can be seen that the availability of early steam, in terms of CO_2 loss to the atmosphere, leads to a reduction from 185 tons to 110 tons per cold start (excluding additional emissions from an auxiliary steam boiler, if any).

In conclusion, the capture system is, intrinsically, a fast response system that depends on the availability of lean amine and, subsequently, on the availability of heat for regeneration to maintain a lean solvent flow into the absorber. Faster engagement of the capture system after roll-off of the gas turbine is an effective lever to reduce CO_2 losses to the atmosphere. Note that the above results did not take into account the thermal limitations that may be presented by specific equipment items, such as limited heat-up rates allowed for heat exchangers. Section 6 specifies a few of these limitations.

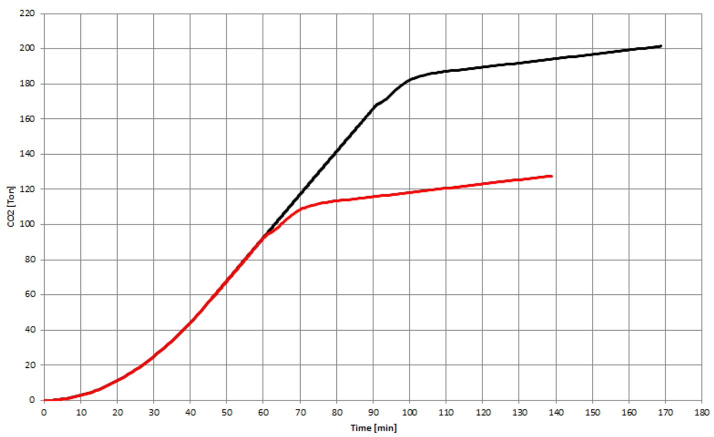


Fig. 18. Cumulative CO_2 loss to the atmosphere upon cold restart with LP steam from steam turbines (black) or with early external steam source of the same quality (red)

5.5. Resulting CO_2 losses to atmosphere as a function of power plant operating mode

The above CO_2 loss data, combined with the start-up frequencies given in Table 1 for commercial power plants in various operating modes, result in the annual CO_2 losses to the atmosphere above the target loss of 10% (target capture ratio of 90%), presented in Table 2. Table 2 presents the data for three cases: the “limited steam” and “early steam” cases presented above, and an additional case that assumes unlimited availability of the capture plant but earliest CO_2 capture only after flue gas supply exceeds the turndown of the flue gas blower, which was assumed to be 50% of full capacity, i.e., 334 kg/s, to be reached ~22 minutes after gas turbine roll-off (Figure 12). At 22 minutes, the cumulative additional CO_2 loss is ~15 tons per start (Figures 15 and 16), indifferent to the type of start. The latter case provides an indication of the best achievable flexibility (where a blower sparing philosophy of 3x50% could allow further tundown).

Table 2. Estimated CO_2 losses per annum per power plant operational mode (Table 1), based on a target capture of 1 mtpa

		Base load plant	Intermediate plant	Cycling plant
Limited steam	kton/annum	5.0	27	76
	%	0.50	2.7	7.6
Early steam	kton/annum	3.0	16	47
	%	0.30	1.6	4.7
Blower turndown	kton/annum	0.44	2.4	6.9
	%	0.044	0.24	0.69

Table 2 learns that, for base load operation, the additional CO_2 losses are negligible with worst case values lower than 1% of the target amount captured. However, for the more future-proof cycling operating mode, in the worst case, additional CO_2 losses could be as high as 8%. This has an immediate impact on the costs of capture that would affect the power price for the consumer. Reducing the loss percentage to below 1%, for a cycling plant, would require measures that accelerate the availability of the capture plant after roll-off of the gas turbine.

6. Measures to accelerate capture availability

In the previous section, it was concluded that accelerating the availability of the capture plant is a key option to reduce CO_2 losses. Measures that could be exploited to accelerate the availability of the capture plant are:

- Utilize instantaneously available absorption capacity, e.g., by:
  - leading flue gas through the absorber upon start-up and starting amine, accepting high amine loadings and CO_2 slip due to lagging regeneration capacity;
  - utilizing waste heat after shutdown in order to lean the solvent before shutdown of the CCS plant and create a buffer for startup;
  - shutting down solvent recirculation upon shutdown of the power plant to prevent mixing of lean and rich solvent;
  - Storing lean (and rich) solvent (like also proposed in [18, 19] for regeneration at a low power price);
- Accelerate heating-up of the CCS system to accelerate absorption kinetics and regeneration capacity, e.g., by:

- designing and operating the power and CCS plant as an integrated system (single optimized LP steam system and LP steam turbine stage, integrated start-up and shutdown sequences);
- routing low-quality dump steam from the HRSG to the capture plant steam system as early as possible;
- using the power plant auxiliary boiler system for capture plant heat-up and/or expand auxiliary boiler capacity;
- minimizing thermal stress exposure by keeping equipment items, like heat exchangers, steam piping and vessels warm during a shutdown period, e.g., by thermal insulation, blocking-in steam or heat tracing;
- shutting down solvent recirculation upon shutdown of the power plant to prevent internal dissipation of heat;
- by-passing the lean/rich heat exchanger during the heat-up period to minimize (internal) heat dissipation;
- switching-off the solvent intercooler and stripper condenser to minimize heat loss during start-up;
- Temporarily, during start-up, operating the direct contact cooler upstream the absorber at 80°C instead of the 40°C normal operating temperature to provide a route for heat input to the solvent in addition to heat input via the reboiler (the latter limited by maximum allowable heat-up rates, see below).

The above acceleration options may require an integrated advanced process control scheme for power and capture plant and need further investigation to identify their value. Some further study was done on the value of the use of reheat steam. The use of reheat steam was found to be limited by the specific heat-up rate of equipment items, due to material integrity limits. For the CO_2 capture plant, the following critical upper limits were identified:

- Steam piping power plant to reboiler: 100°C/hr;
- Reboiler vessel: 100°C/hr;
- Heat exchanger on the reboiler: 60-100°C/hr, depending on the type of exchanger (the lower limit valid for welded plate heat exchangers).

6.1. Use of dump steam for start-up

The start-up scheme of Figure 19 is proposed with the above equipment limitations as a starting point and making use of low-quality dump steam that is produced by the HRSG system and, normally, dumped in the condenser prior to engagement of the steam turbine. Due to limited availability of data, a gas turbine start-up to full power in 90 minutes was taken as an example. After roll-off of the gas turbine, in a hot restart (which will be by far the most abundant start-up in a future cycling power plant), low-quality steam (called "reheat steam") becomes available after 20 minutes, which is 60 minutes before LP steam becomes available. At that point the steam piping from HRSG to reboiler can be heated, which takes 20 minutes. Subsequently, the steam/solvent heat exchanger on the reboiler can be heated, which will take 30 minutes. Next in line are the reboiler vessel and the solvent inventory. Overall, the capture plant in this way may become fully available 100 minutes after roll-off of the gas turbine. The feasibility of such system needs to be further assessed.

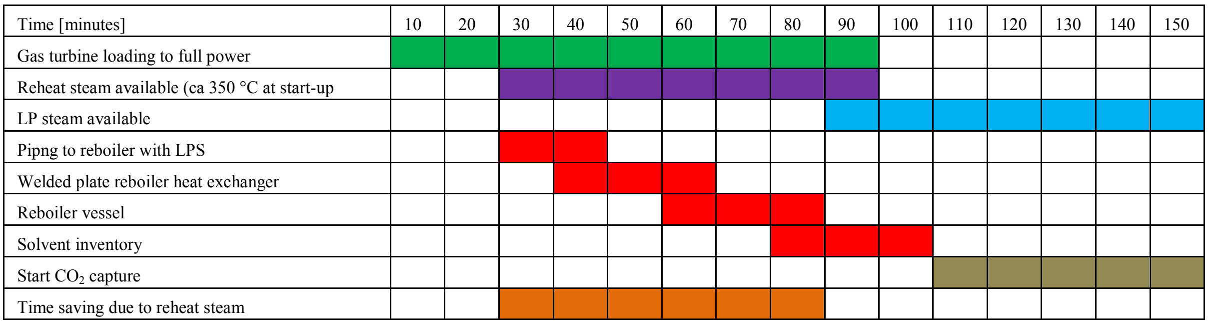


Fig. 19. Start-up scheme example, based on the use of hot reheat steam and taking into account heat-up limitations (yellow bars indicate heat-up from ambient to operating temperature)

Although the above is only an example, it provides a strong indication that the capture plant can become fully available, probably even earlier than the “early steam” case used in the dynamic calculations of Section 5.4. Anticipating successful utilization of at least some of the identified options for acceleration, it seems feasible to obtain a system that performs somewhere in between the “50% blower turndown” case and “early steam” cases of Table 2 for a case without an auxiliary steam boiler.

7. Discussion and Conclusions

The flexibility of gas-fired power plants for mid-merit cycling or base-load operation does not have to be limited by the addition of amine-based post-combustion CO_2 capture. This is in line with the findings by other authors [19, 20]. An amine-based CO_2 capture plant can demonstrate fast dynamics that allow for load following as well as fast shutdowns without additional CO_2 losses. Start-up scenarios may lead to additional CO_2 losses, which can be limited to a small percentage of the CO_2 capture target with the appropriate design of equipment and control schemes. Key, in this respect, is the availability of lean solvent, as a CO_2 buffer, as well as the availability of heat, e.g., low-quality steam, for effective solvent regeneration and favorable CO_2 absorption kinetics. Various options to accelerate the capture rate, partly driven by equipment limitations, have been identified and require further study and development to explore their value. The dynamic modelling capability built for this study provides an excellent tool to do this.

It is noted that, starting from early FOAK CCGT-CCS power plants, a learning curve will be required to further develop flexible operation. Reference is made to the learning curve that delivered the current flexibility of CCGT power plants, where the steam cycle follows load variations on the gas turbine. Notably, a capture plant requires only low-quality steam to provide heat to only static equipment. Hence, faster learning is anticipated while building on the CCGT’s learnings in steam systems and controls.

Also, it should be noted that the current study only regarded the power plant and capture plant, excluding CO_2 conditioning, compression, transport and injection. Studies on the integrated low-CO_2 power supply chain dynamics will be reported separately.

8. Acknowledgements

The authors would like to thank the numerous PSE engineers that supported this study. Special thanks go to Nouri Samsatli, Adekola Lawal, Mario Calado and Elton Dias for their strong commitment to developing the model.

References

[1] Bradbury, S. Wind power and other renewable sources of Energy – managing intermittency. Oil&Gas UK Energy Policy Seminar, Nov 10, 2011, Aberdeen, UK;
[2] Isles, J. El Segundo combined cycle offers 300 MW of peaking in 10 minutes. Gas Turbine World. September-October 2013;
[3] Ballings, L. Fast Cycling and rapid start-up: new generation of plants achieves impressive results. Modern Power Systems. January 2011;
[4] Cox, J. The challenge of integrating intermittent renewables. A Pöyry presentation to IMETS, October 2012;
[5] Natural Gas in Low-Carbon Electricity Systems. In; Energy Technology Perspectives 2014, IEA 2014.
[6] Foster-Wheeler report FWI No. 1-BD-0530 A: Operating Flexibility of Power Plants with CCS, November 2011;
[7] Maas, W., Mirfendereski, Y., Schlange, B., Spanjer, A., Valente, J. Techno-economic evaluation of CCS for low-CO_2 gas power. Power Gen. Europe, Cologne, Germany; 12-14 June; 2012;
[8] Ramos, A. et al. CCS System Modelling: Enabling Technology to Help Accelerate Commercialisation and Manage Technology Risk. 4th Korean CCS Conference, February 2014, Jeju Island, South Korea;
[9] Lawal, A. et al.. Hazard analysis of carbon capture and storage systems, 13th Carbon Capture, Storage and Utilisation Conference, May 2014, Pittsburgh, US;
[10] Ramos, A. et al.. “CCS System Modelling - Impact of power plant flexibility on CCS networks”, All-Energy 2014, May 2014, Aberdeen, UK;

[10] Chapman, W. G., Gubbins, K. E., Jackson, G., & Radosz, M. (1990). New reference equation of state for associating liquids. Industrial & Engineering Chemistry Research, 29(8), 1709-1721;
[12] Gil-Villegas, A., Galindo, A., Whitehead, P. J., Mills, S. J., Jackson, G., & Burgess, A. N. (1997). Statistical associating fluid theory for chain molecules with attractive potentials of variable range. The Journal of chemical physics,106, 4168;
[12] Lymperiadis, A., Adjiman, C. S., Jackson, G., & Galindo, A. (2008). A generalisation of the SAFT group contribution method for groups comprising multiple spherical segments. Fluid Phase Equilibria, 274(1), 85-104;
[14] Papaioannou, Vasileios. A molecular-based group contribution equation of state for the description of fluid phase behaviour and thermodynamic derivative properties of mixtures (SAFT-γ Mie). Diss. Imperial College London, 2013;
[15] Billet, R. and M. Schultes, M. Prediction of mass transfer columns with dumped and arranged packings: updated summary of the calculation method of Billet and Schultes. Chemical Engineering Research and Design 77.6 (1999): 498-504;
[16] Billet, R. and M. Schultes. Modelling of pressure drop in packed columns. Chemical Engineering & Technology 14.2 (1991): 89-95;
[17] Analysis of CCGT power plant operational data over 2011;
[18] Ruchti, C. et al. Combined cycle plants as essential contribution to the integration of renewables into the grid.VGIEI-Combined Cycle Power Plants, September 2012;
[19] Van Peteghem, T., Delaru, E. Opportunities for applying solvent storage to power plants with post-combustion carbon capture. Int. J. Greenhouse Gas Control; Vol. 21; 203-213; 2014;
[20] Haines, M.R., Davison, J.E. Designing Carbon Capture power plants to assist in meeting peak power demand. Energy Procedia; Vol. 1; 1457-1464; 2009.
[21] Domenichini, R. et al. Operating flexibility of power plants with carbon capture and storage (CCS). Energy Procedia; Vol. 37; 2727-2737; 2013.